FACT SHEET FOR
PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
Satsop Combustion Turbine Project No. EFSEC/2001-01 Amendment 2
Grays Harbor County, Washington
July 2, 2004

1 INTRODUCTION

1.1 THE PSD PROCESS

The Prevention of Significant Deterioration (PSD) procedure is established in Title 40, Code of the Federal Regulations (CFR), Part 52.21. Federal rules require PSD review of all new or modified air pollution sources that meet certain criteria. The objective of the PSD program is to prevent serious adverse environmental impact from emissions into the atmosphere by a proposed new source. The program limits degradation of air quality to that which is not considered "significant." It also sets up a mechanism for evaluating the effect that the proposed emissions might have on environmentally related areas for such parameters as visibility, soils, and vegetation. PSD rules also require the utilization of the most effective air pollution control equipment and procedures, after considering environmental, economic, and energy factors.

The Washington State Energy Facility Site Evaluation Council (EFSEC) is the PSD permitting authority for thermal energy facilities with a net electrical output greater 350 Megawatts (MW), sited in the state of Washington, per Chapter 80.50 of the Revised Code of Washington (RCW) and Chapter 463-39 of the Washington Administrative Code (WAC).

1.2 THE PROJECT

1.2.1 HISTORY OF THE PROJECT

Energy Northwest and Duke Energy of North America (jointly referred to as Duke Energy or Duke) are requesting an extension of the time period allowed to suspend construction by 18 months, modify specific monitoring provisions, and other specific changes to subparagraphs of approval conditions in EFSEC Permit No. EFSEC/2001-01, Amendment 1. Duke Energy submitted the application on January 19, 2004. Additional information relating to the review of this request to amend the NOC/PSD approval was received by EFSEC from the applicant on February 27, 2004; however, EFSEC's PSD permit writing contractor did not receive this information until attending a meeting with Duke Energy and EFSEC on March 11, 2004. This application was deemed administratively complete on April 10, 2004.

In 2001, Duke Energy requested an amendment to EFSEC Permit NO. EFSEC/2001-01 for the Satsop CT Project to authorize the construction of an expansion to include an additional "power island" (described below) and associated equipment (phase II), to include additional equipment to the Satsop CT project not included in the original approval, and a request to remove specific operational restrictions included in EFSEC permit NO. EFSEC/2001-01. Prior to issuance of Amendment 1, the applicant requested deletion of all Phase II project conditions and criteria. This request was reflected in the final version of Amendment 1.

Construction and operation of the Satsop CT Project was originally authorized by the Energy Facility Site Evaluation Council in 1995 (EFSEC) by issuance of a Site Certification Agreement containing PSD permit No. EFSEC/95-01, issued in 1996. After two consecutive permit extensions in March 1998 and September 1999, the PSD permit expired prior to the applicant's starting construction of the facility. In April 2001, Duke Energy submitted a new PSD application for the Satsop CT Project. NOC/PSD approval No. EFSEC/2001-01 was issued in November 2001. EFSEC authorized the start of construction of the Satsop CT project in September, 2001, prior to issuance of the new PSD approval as allowed by an Administrative Order on Consent issued by EPA in June 2001.

As allowed under 40 CFR 52.21(r)(2) the project owner may request an extension of the allowable time to begin construction or suspend construction of a project that has started construction. Approval of such a request is not automatic and is subject to EFSEC's approval (acting as the Administrator under EFSEC's PSD delegation agreement and regulations). Draft federal guidance on addressing requests to extend the 18 month period allowed to start construction (or suspend construction) without having to reapply for a new PSD approval indicates that a request for extension should include a re-evaluation of the Best Available emission Control Technology (BACT) reflected in the permit approval conditions. Duke Energy submitted this request along with a review of BACT for the combustion turbines and other equipment installed at the plant. This re-evaluation of BACT and new information on actual plant operations supplied by Duke Energy was used to update the BACT determination for this project.

1.2.2 THE PROJECT

Duke Energy began construction of the facility in September, 2001, actively installing most major equipment and completing much of the site construction prior to suspending construction January 21, 2003. Officially Duke Energy classes construction as approximately 60% complete. Staff remains on site performing preventative maintenance on the installed equipment and some minor new equipment installation activities. The major construction elements remaining to be erected at the facility are installation of heat recovery steam generator (the ductwork to hold the steam generator has been mostly installed), the exhaust stack and process control system. Duke Energy estimates that it would take up to 12 months to complete construction and begin initial equipment start-up operations once construction is formally resumed.

The partially constructed electric generating facility is located near the town of Elma, Washington, on the south side of the Chehalis River within the Satsop Development Park. The partially constructed Satsop CT Project will generate 600 MW, nominal (650 MW, peak).

The partially constructed project is comprised of the following equipment:

- Two General Electric GE 7FA, gas combustion turbines (maximum fuel consumption rating of 1,671 million British thermal units per hour (mmBtu/hr)) connected to an electrical generator rated at 175 MW, nominal;
- One heat recovery steam generator (HRSG) and supplementary duct burner per turbine (maximum fuel consumption rating of 505 mmBtu/hr);
- One steam turbine-generator unit powered by steam produced in the HRSGs rated at 300 MW, nominal;
- One auxiliary boiler rated at 25,000 pounds steam per hour;
- One 9 cell forced draft/evaporative cooling tower;
- One emergency diesel engine generator; and
- One diesel engine fire water pump.

All combustion equipment except the diesel fueled emergency generator and fire water pumps are fueled by natural gas received from the Williams Co.'s., Northwest Pipeline. The diesel fuel proposed for use in the diesel engines is on-road specification diesel with less than 0.05% sulfur by weight. As diesel fuel sulfur content specifications are adjusted in the future, fuel meeting the then current on-road specifications for diesel fuel will be required to be purchased for use.

Filtered air is compressed in the compressor stage of each turbine and is then mixed with natural gas which is burned in the combustion chambers of each turbine. Exhaust gas from the combustion chambers is expanded through power turbines to recover energy released from combustion to run the compressor section of the turbine and to directly power an electric generator. Heat in the turbine exhaust is recovered in the HRSG. When additional electrical production capacity is required, the turbine exhaust can be heated further by the duct burner, providing additional heat energy to the HRSG to make additional steam. Steam from the HRSG is used to power the steam turbine connected to an electric generator. This arrangement of combustion turbine, steam generation and steam turbine is known as a combined cycle gas turbine (CGT).

Excess heat left over in the HRSG water from the steam turbine is removed by cooling towers. The auxiliary boilers are used to assist start-up of the combustion turbine by initially heating the boiler water in the HRSGs. Using the auxiliary boiler to hear the HRSG water speeds up the transition from cold plant to full operation, reduces the opportunity for thermal stress cracking of the HRSG boiler tubes, and to provide sealing steam for the steam turbines under normal operation. The emergency generators are used to help power down equipment and maintain operation of cooling and boiler water pumps in the event of a system power outage. The fire water pumps are for fire suppression use if the electrical power system is down.

Duke Energy is proposing to control nitrogen oxides (NO_x) carbon monoxide (CO) and volatile organic compounds (VOC) emissions from the gas turbines and heat recovery steam generators by the use of dry-Low NO_x combustors in combination with Selective Catalytic Reduction (SCR). Burning natural gas as fuel will control particulate matter, sulfur dioxide and sulfuric acid to low levels.

1.2.3 APPLICABLE REGULATIONS

1.2.3.1 Federal New Source Performance Standards (NSPS)

1.2.3.1.1 40 CFR 60, Subpart GG applies to the combustion turbines and limits NO_x, sulfur dioxide (SO_2). The NO_x limit in Subpart GG for these stationary gas turbines burning natural gas, and using the turbine's lower heating value heat rate, is calculated to be 135 parts per million by volume dry (ppm) corrected to 15 percent oxygen. Sulfur dioxide emissions are limited to either 150 ppm corrected to 15% oxygen or a fuel containing more than 0.8 percent sulfur.

1.2.3.1.2 40 CFR 60, Subpart Da applies to fossil fuel fired steam electric utility units with a heat input capacity above 250 mmBtu/hr. This regulation applies to the gas-fired duct burners for the proposed Project. Under this NSPS, PM, SO_2 and NO_x emissions from the duct burners are limited to 0.03, 0.20, and 0.20 pounds/mmBtu, respectively. At the proposed maximum firing rate of 505 mmBtu/hour, these limits translate to 15.2 pounds per hour of particulate matter, 101 pounds per hour of SO_2 and 101 pounds per hour of NO_x.

1.2.3.1.3 40 CFR 60, Subpart Dc applies to fossil fuel fired steam generator units with a heat input between 10 and 100 mmBtu/hour. This regulation applies to the auxiliary steam boilers. Under this NSPS there are no emission limits, but there are monitoring and reporting requirements that apply to natural gas fueled units.

1.2.3.2 Federal National Emission Standards for Hazardous Air Pollutants, Maximum Achievable Control Technology

1.2.3.2.1 40 CFR 63, Subpart YYYY applies to combustion turbines located at major sources of Hazardous Air Pollutants (HAPS) that began construction or began reconstruction after January 14, 2003. The Satsop Combustion Turbine project with the turbines emitting less than 3 tons of formaldehyde per year is not a major source of HAPS. Thus this facility does not have to comply with this regulation.

1.2.3.3 Acid Rain Program

1.2.3.3.1 40 CFR Parts 72 and 75 Acid Rain Program is applicable to this plant. Prior to the start of operation, the plant will need to apply to EPA for SO_2 allowances and an acid rain permit issued under 40 CFR 72 and WAC 463-39-005(3) (referring to Chapter 173-406 WAC).

40 CFR 72.2 limits natural gas sulfur from power plants subject to the provisions of the federal Acid Rain program. The regulation defines two types of natural gas, "pipeline natural gas" and "natural gas". The total sulfur in "pipeline natural gas" is restricted to 0.5 grains per 100 standard cubic feet (gr/100 scf) and the total sulfur content of "natural gas" is restricted to 20 gr/100 scf.

1.2.3.4 Prevention of Significant Deterioration

Chapter 463-39-005(1) WAC adopts the Department of Ecology Regulation Chapter 173-400 WAC by reference. This Department of Ecology regulation adopts the federal PSD program found at 40 CFR 52.21 by reference. Through EFSEC's adoption of the Department of Ecology regulation, EFSEC has requested and received a partial delegation of the PSD program from EPA. The partial delegation requires EPA to sign all PSD permits that have NOx as a PSD significant pollutant.

1.2.3.5 Control of Emissions form New and In-use Nonroad Compression-Ignition Engines

40 CFR Part 89 governs the emissions from non-road diesel fired engines. In Subpart B (40 CFR 89.112) of the regulation, specific emission limitations are established for different engine sizes and year of manufacturer. The diesel engines proposed for use as emergency generators and emergency fire water pumps are subject to these requirements.

1.2.3.6 State Regulations

The facility is subject to Notice of Construction requirements under EFSEC regulations, Chapter 463-39 WAC. This regulation adopts the Washington Department of Ecology air quality regulations, Chapters 173-400, 173-401, 173-460 WAC, by reference.

2 DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

2.1 DEFINITION

According to state and federal clean air laws, all new sources of air pollution are required to utilize Best Available Control Technology (BACT). BACT is defined as an emission limitation based on the most stringent level of emission control available or applied at an identical or similar source (40 CFR 52.21(b)(12)) and WAC 173-400-030(12). The Satsop CT must achieve this level of control or prove it is technically or economically infeasible before a less stringent level of control is allowed.

2.2 BACT FOR GAS TURBINE/HEAT RECOVERY STEAM GENERATOR SYSTEMS

2.2.1 NITROGEN OXIDES CONTROL

NO_x is generated during the combustion of fuels. NO_x is generated during combustion from the nitrogen in the air reacting with oxygen or from the reaction of nitrogen compounds in the fuel with oxygen. The use of natural gas minimizes the total quantity of NOx that is generated compared to other fuels because natural gas contains essentially zero fuel bound nitrogen. The emissions of NO_x can be controlled through the use of combustion modifications or add-on emission control technologies.

NOx participates in the formation of tropospheric ozone, photochemical smog, and acid rain. In conjunction with ammonia and similar gases, NOx can also cause degradation in regional visibility (regional haze).

The following control technologies were considered for NOx reduction from the combustion turbine/duct burner units:

2.2.1.1 Steam or Water Injection:

Steam or Water injection are similar technologies that have been widely used as a gas turbine NO_x emission control. Steam or water is injected into the combustion zone to lower the peak combustion zone flame temperature. High-purity water must be used to prevent turbine corrosion, deposition of solids on the turbine blades, or particulate erosion of the turbine blades.

Typical steam/water injection rates range from 0.5 to 2.0 pounds of steam and 0.3 to 1.0 pounds of water per pound of fuel. The NOx reduction efficiency of the steam/water injection to reduce NO_x emissions depends on turbine design. Typical emission rates of 25 – 42 ppm @ 15% O_2 are capable of being produced through the use of steam/water injection. For a given turbine design, the maximum water/fuel ratio (and maximum NO_x reduction) will occur up to the point where cold-spots and flame instability adversely affect safe, efficient, and reliable operation of the turbine. Different turbine designs have different maximum water/fuel ratios.

This technology alone will not satisfy regulatory requirements without the addition of a post-combustion control. This technology is not proposed for implementation on the Satsop CT Project.

2.2.1.2 Dry Low NO_x Combustor:

The modern, dry low NO_x combustor technology is typically a three-stage, lean, premix design, which utilizes a central diffusion flame for overall flame stabilization. The lean, premixed approach burns a lean fuel-to-air mixture for a lower peak combustion flame temperature resulting in lower thermal NO_x formation. The combustor operates with one of the lean premixed stages and the diffusion pilot at lower loads and the other stages at higher loads. This provides efficient combustion at lower temperature, throughout the combustor-loading regime. The dry low-NO_x

combustor reduces NO_x emissions by up to 87 percent over a conventional combustor. Typical emission rates of 9 – 25 ppm @ 15% O_2 can be achieved through this design.

An advanced, Dry Low NOx combustor will be an integral part of the combustion turbines permitted for the project. This technology is guaranteed by the manufacturer to reduce NO_x emissions from the combustion turbines to 9 ppm for natural gas firing. While this technology has the lowest overall costs and environmental impact, it does not satisfy current regulatory requirements without the addition of a post-combustion control.

2.2.1.3 XONON:

This technology provides combustion modifications by lowering the peak combustion temperature to reduce formation of NO_x while also providing further control of CO and unburned hydrocarbon emissions that other NO_x control technologies cannot provide. The overall combustion process in the XONON system is a partial combustion of the fuel in a catalyst module, followed by completion of the combustion downstream of the catalyst. The manufacturer has demonstrated on its small test units the technology is capable of producing NO_x emissions or 2 ppm or lower.

XONON is an innovative technology that is currently commercially available only for certain small combustion turbines, typically with electrical outputs below 10 MW in simple-cycle mode. This technology has not been proven nor is it commercially available for turbines within an equivalent size range as that proposed for the Satsop CT Project. Therefore, this technology is deemed technically infeasible for use on this size class of combustion turbine.

2.2.1.4 SCONOX:

This technology is a post-combustion control system which uses a carbonate coated catalyst installed to remove both NO_x and CO without use of a reagent such as ammonia. The NO_x emissions are oxidized to NO_2 and then adsorbed onto the catalyst. CO is oxidized to CO_2. The concentration of VOC in the flue gas is partially reduced as well. A dilute steam of hydrogen gas is passed through the catalyst periodically to desorb the NO_2 from the catalyst and reduce it to N_2 prior to exit from the stack. This control technology is utilized on a small combustion turbine, approximately 28 MW, in Vernon, California in December 1996.

Only one equivalent sized turbine project in California has a permit which includes SCONOX as the NO_x control for a GE 7F scale combustion turbine. One of the 4 turbines at this facility is permitted to use either SCONOX or SCR, but, regardless of the technology used, must meet the same Lowest Achievable Emission Rate based emission limitation. This facility is located in an ozone nonattainment area. Therefore, SCONOX is considered technically feasible but unproven for large power plants such as the Satsop CT Project.

Cost data submitted to Duke Energy by SCONOX's vendor for installation as part of original construction indicates that annualized cost would be $4,757,834 million per turbine resulting in an incremental cost effectiveness of $12,521 per ton of NOx removed. The cost for SCONOX is unreasonably high and above the range considered cost effective for comparable projects.

As indicated above, this facility is partially constructed and the cost of retrofitting the existing HRSG to include SCONOX has not been evaluated. Nonetheless, EFSEC finds that SCONOX continues to be technically feasible, but economically not cost effective to implement at this facility.

2.2.1.5 Selective Catalytic Reduction:

Selective catalytic reduction (SCR) is a post-combustion NOx control technology where ammonia (NH_3) is injected into the flue gas, upstream of a vanadium oxide based catalytic reactor. The catalyst bed operates at a temperature between 600 and 800°F, temperatures typically found within the HRSG unit. On the catalyst surface, the NH_3 reacts with NOx to form molecular nitrogen and water. Typical SCR Systems are designed to achieve NO_x emission rates of 2 – 5 ppm.

The process uses approximately 1 – 1.3 moles of NH_3 per mole of NO_x reduced and to assure that there is adequate NH_3 for the NO_x reduction reaction to take place. PSD approvals and other permits commonly establish an allowable ammonia 'slip' of 5 to 10 ppm when permitting of SCR on combustion turbines. Actual operation of existing facilities in Washington demonstrate that slip levels below 5 ppm routinely occur. However, the equipment manufacturers have not always been willing to guarantee meeting the NO_x emission rates with NH_3 limits below 10 ppm.

The primary variable affecting NO_x reduction is temperature. If operating below the optimum temperature range, the catalyst activity is reduced, allowing unreacted NH_3 to slip through into the exhaust stream. If operating above the optimum temperature range, NH_3 is oxidized, forming additional NO_x, and the catalyst may suffer thermal stress damage.

With the proper selection of catalyst support material, catalyst materials, and careful catalyst installation, SCR can be used effectively on flue gas streams that contain large amounts of particulate matter and sulfur dioxide. SCR units are now being routinely installed at new and existing coal fired power plants to control NOx emissions. These installations commonly locate the SCR catalyst in high particulate and SO_2 concentration conditions in the flue ducts of these coal fired plants.

There are several environmental concerns associated with SCR control technology. The primary concern is that ammonia emissions are released when ammonia passes through the catalyst unused, and is exhausted through the stack. Ammonia slip may range from less than 5.0 ppm during normal operations to 50.0 ppm during start-ups. The emission of ammonia from the turbine will tend to increase the impacts of the turbine on regional haze and nutrient (ammonium sulfate and ammonium nitrate) deposition within Class 1 and 2 areas. At this time, the EPA, the U.S. Forest Service, and the National Park Service have considered the control of NO_x to be more important than the potential adverse impacts of ammonia on regional haze or nutrient deposition.

Ammonia is frequently shipped by rail or highway and during transport a small potential exists for a spill due to a vehicle accident. The applicant is proposing to use an aqueous solution of ammonia to reduce adverse handling and shipping problems. Spills may occur during the transfer of aqueous ammonia from one container to another or catastrophic failure of a storage tank. This is a very rare occurrence and is addressed by spill containment and control requirements. Another negative side effect from using the SCR process is the formation of sulfur trioxide (SO_3) from some of the SO_2 in the exhaust gas. SO_3 reacts with ammonia in the exhaust gas to produce ammonium sulfate and ammonium bisulfate salts. These salt compounds create corrosion and deposition problems within the heat recovery system and will require more maintenance at the HRSG. Some of these ammonium salts leave the exhaust stack and contribute to visibility of both the plume and to regional haze.

Duke Energy has proposed to use GE dry low NO_x combustors on the turbine, low NO_x burners for the duct burners, and SCR to reduce the concentration of NOx. Duke Energy has suggested that the BACT emission limitation should be 3 ppm NOx rather than the current BACT of 2.5 ppm. EFSEC has determined that the BACT emission limitation for NOx continues to be 2.5 ppm which results in a reduction of NOx emissions from approximately 88.7 lb/hr (with duct burners operating) to 21.7 lb/hr (16 ppm to 2.5 ppm). The annualized cost provided by Duke Energy for using SCR to provide this level of emissions reduction is $1,728,500 per turbine or $4,767 per ton of NO_x reduced under full plant operation. These costs are within the upper end of the range of costs normally encountered for the emission controls representing NO_x BACT for natural gas fired combustion turbines in Washington and the EPA Region 10 states.

Dry low NO_x combustors, low NO_x burners for the duct burners, plus SCR are considered to be BACT for this project. This control system will control NOx emissions from each CGT to 2.5 ppm and 9.86 kilogram/hour (21.7 pound/hour) are considered to be BACT for this project.

2.2.1.6 The following table lists the emission controls considered for BACT and provides a quick synopsis of the above material.

TABLE 1
NO_x EMISSION CONTROL FOR AVAILABLE CONTROL TECHNOLOGIES FOR EACH CGT AT THE SATSOP COMBUSTION TURBINE PROJECT

Emission Control Mechanism	NO_x Emission Concentration (ppmvd @ 15% O2 and ISO)	NO_x Emission Rate kg/hr (lb/hr)	Control Efficiency (Ratio to NO_x Control	Cost Effectiveness ($/ton pollutant controlled)
Conventional Combustor Low NO_x duct burner Total emissions	72.4 8.3 80.7	285.2 (628.8)* 20.1 (44.2) 305.3 (673.0)	0%	0
Dry Low NO_x(DLN) Combustor Low NO_x duct burner Total emissions	9** 8.3 17.3	35.4 (78.1) 20.1 (44.2) 55.5 (122.3)	87.6%	0
DLN w/SCR (with duct burner firing)	2.5**	9.84 (21.7)**	96.5%	$4,767
DLN w/SCONOX (with duct burner firing)	2**	7.89 (17.4)**	97.2%	$12,521

*Based on AP-42, Section 3.1, Table 3.1-1, April 2000, for turbine emissions and AP-42, Section 1.4, Table 1.4-1, September 1998, for duct burner emissions. At maximum duct burner operating rate, the duct burner contributes 8.3 ppm to the NO_x emissions.
**Emissions calculated by General Electric and Duke/Fluor-Daniel.

2.2.1.7 Emission Limits, Monitoring and Reporting requirements for NO_x:

SCR with dry low NO_x combustors and Low NO_x duct burners represent BACT for NO_x control. The NO_x from each CGT shall not exceed a 1 hour average of 2.5 ppm at 15% O_2 and ISO conditions, and 9.84 kg/hr (21.7 lb/hr). This represents the maximum emission rate which occurs while duct firing is occurring.

As discussed later in the ambient air quality impacts section, the protection of Olympic National Park from adverse visibility impacts requires a lower NOx limitation for the facility than required by BACT. Visibility modeling indicates that an emission limitation of 2.0 ppm NOx, 24 hour average is necessary to protect the park form adverse visibility impacts. Thus in addition to the BACT emission limitation, there is also an emission limitation reflecting the requirement to protect Olympic National park from adverse visibility impacts. Prior evaluation by this and other regulatory agencies has determined that the difference in annual cost to achieve 2.0 ppm on a 24 hr. average basis and 2.5 ppm on a 1 hour basis is insignificant.

NO_x emissions, exhaust gas O_2 content, and flow rate from each exhaust stack shall be measured and recorded by a continuous emission monitoring system that meets the requirements of 40 CFR 75. Emissions reporting to EPA for compliance with the Acid Rain program shall be on the frequency and in the format required by EPA. This same information will be supplied to EFSEC on the same reporting frequency.

2.2.2 CARBON MONOXIDE CONTROL

Carbon monoxide (CO) is an odorless, colorless, toxic gas that is formed when carbon containing compounds are burned. The rate of formation for CO is directly related to combustion efficiency, available oxygen, and combustion temperature. In the atmosphere, CO is converted to carbon dioxide over a period of a few days. Because of its adverse health effects, CO has been considered to be an important compound to control to protect the public health.

The following control options considered for CO control:

2.2.2.1 Dry Low NO_x combustors:

The use of dry low NO_x combustors on the gas turbines and low NO_x combustors for the duct burners is the base emissions case for this project. The dry low NOx combustors are designed to minimize the formation of NO_x while also working to minimize the formation of CO. These are usually opposing functions, but the manufacturers have been able to optimize the combustors to minimize both compounds.

The earlier versions of this approval based the uncontrolled CO reduction calculations on a turbine exhaust concentration of approximately 22 ppm. This resulted in a very high pollutant control and low control cost effectiveness. More recent information from the manufacturer of the combustion turbines indicate that the dry low NO_x combustors will have a CO emission rate of 9 ppm. Long term CEM results on other Duke Energy combustion turbines using the same model GE turbine installed at the Satsop CT facility indicate that except for start-up and shutdown operations, uncontrolled hourly average values emissions are always well below 6 ppm. A calendar quarter of CEM data supplied by Duke Energy for their Washington Energy Facility in Beverly Ohio indicates no single hour of normal operation above 2.7 ppm and the vast majority being below 1 ppm.

The low NO_x combustors for the duct burners are rated by the manufacturer to produce 13.6 ppm. Duke Energy experience with these burners on other facilities indicates that actual duct burner emissions are also well below 6 ppm. The combined emission rate of the duct burners and the combustion turbine would then be in the 3 to 9 ppm range. A CO emission rate higher than 3 – 5 ppm is within the range of CO concentrations that have been accepted as BACT for CGTs in Washington for number of years.

2.2.2.2 SCONOX:

CO is also controlled by the SCONOX process. SCONOX oxidizes CO and some VOCs to CO_2 and water through the use of a platinum catalyst. Through the use of SCONOX, CO emissions can be reduced by 90+%, resulting in emission concentration of 1 – 2 ppm. The SCONOX system would remove 302 tons of CO per CGT per year at a cost effectiveness of $15,574. This cost is considerably above the normal range of cost effectiveness applied to CGTs for CO control.

SCONOX has the ability to reduce multiple pollutants. A cost effectiveness analysis using the 'excess cost" above the cost attributable to reduce NO$_x$ can be applied to a CO reduction BACT cost effectiveness determination. Using this concept, the excess annual cost of SCONOX applicable for evaluating SCONOX for CO control results in a cost effectiveness of $11,688/ton CO reduced. This is cost is above the normal range of cost effectiveness for CO control systems applied to CGTs for CO control and does not include any additional costs that may need to be incurred to retrofit the installed equipment to accommodate SCONOX.

2.2.2.3 Catalytic Oxidation:

The most common means to control carbon monoxide on combustion turbines is catalytic oxidation. The hot exhaust gas passes through a platinum catalyst section where oxygen in the gas stream is reacted with CO to produce CO$_2$. Some of the VOCs in the flue gas also react to form CO$_2$ and water.

This technology is capable of reducing CO concentration by 90+%. As noted above, the actual uncontrolled emission rate of CO is less than 6 ppm, 1 hour average, from a similar turbine installation operated by Duke Energy. A common BACT emission limitation (and what was include in the original approval) in Washington has been 2 – 3 ppm, 1 hour average. Assuming that the uncontrolled CO concentration is as high as 6 ppm, a 2 ppm emission limitation is a 67% reduction in CO and amounts to approximately 40.5 tons of CO reduced. The resulting cost effectiveness of this emissions rate is estimated to be $15,655 per ton. This cost effectiveness is well above the normal range of cost effectiveness' for CO control systems.

2.2.2.4 The following table lists the emission controls considered for CO BACT and provides a quick synopsis of the above material.

TABLE 2
CO EMISSION CONTROL FOR AVAILABLE CONTROL TECHNOLOGIES FOR EACH CGT AT THE SATSOP COMBUSTION TURBINE PROJECT

Emission Control Mechanism	CO Emission Concentration (ppm @ 15% O$_2$)	CO Emission Rate kg/hr (lb/hr)	Control Efficiency (Ratio to CO Control	Cost Effectiveness ($/ton pollutant controlled)
Dry Low NO$_x$(DLN) Combustor Low NO$_x$ duct burner Total emissions	6** 6 6	9.09 (20.0) 4.77 (10.5) 13.86 (30.5)	0%	0
Dry Low NO$_x$(DLN) Combustor with Low NO$_x$ duct burner	3***	6.62 (14.6)	0%	0
DLN w/CO catalyst (with duct burner firing)	2.0**	4.81 (10.6)**	66.7%	$15,655
DLN w/SCONOX (with duct burner firing)	2.0**	4.81 (10.6)**	66.7%	$11,688

*Based on AP-42, Section 3.1, Table 3.1-1, April 2000, for turbine emissions and AP-42, Section 1.4, Table 1.4-1, September 1998, for duct burner emissions. At maximum duct burner operating rate, the duct burner contributes 13.6 ppm to the CO emissions.

**Emissions calculated by General Electric and Duke/Fluor-Daniel.

*** Based on data supplied with BACT re-analysis

2.2.2.5 Determination of BACT for CO

Based on the Duke Energy data submitted to EFSEC and current and historical BACT determinations on CO from combined cycle combustion turbines EFSEC proposes a BACT emission limitation of 3 ppm, 3 hour average, applicable to operations with and without duct burners. The data supplied indicates that this limitation can be met without the use of add on emission controls and that the already constructed HRSG includes space to install a oxidation catalyst if necessary to comply with the limitation.

2.2.2.6 Emission limits and Monitoring Requirements for CO:

Based on the above and additional information submitted by Duke Energy, BACT for CO control is dry low NOx combustors and low NOx duct burners. CO emissions from each CGT exhaust stack shall not exceed a 3 hour average of 3 ppm at 15% O_2, and 6.62 kg/hr (14.6 lb/hr) with and without duct firing.

Each turbine stack will be equipped with continuous CO monitors that meet the requirements of 40 CFR 60, Appendices B and F. The emissions will be complied and reported to EFSEC on the same schedule as the NO_x emissions.

2.2.3 VOLATILE ORGANIC COMPOUNDS (VOC)

Volatile organic compounds encompass organic compounds that participate in ozone formation reactions with NO_x. Some of these compounds are innocuous, some can be quite toxic, and the rest range somewhere in between. In the atmosphere, these compounds react with NO_x and other photoactive chemicals to form ozone and other nitrogen containing, reactive organic chemicals. The dominant VOCs found in the exhaust of a gas combustion turbine are aldehydes such as formaldehyde and acetaldehyde.

The following control options were considered for VOC control:

2.2.3.1 Dry Low NO_x combustors and low NO_x duct burners:

This is the "no further control" option. The VOC control technologies discussed below are based on volatile organic compound emission reductions from this level. The VOC emissions from use of these combustors is, 2.8 ppm at 15% O_2, 24 hour average, and 2.86 kg/hr (6.3 lb/hr), both expressed as carbon equivalent. The BACT cost effectiveness is $0. The use of dry low NOx combustors and low NOx duct burners fired on natural gas represents BACT for VOC emission control for this source.

2.2.3.2 Thermal Oxidation, Carbon Adsorption, Condensation and Absorption:

There is concern for the application of these technologies to the very dilute VOC concentrations and high temperatures in the exhaust of a combustion turbine. All of these technologies have demonstrated better efficiencies when used to control exhausts containing significantly higher concentrations of hydrocarbons. As such, these technologies are currently considered to be technically infeasible for use on combustion turbines.

2.2.3.3 SCONOX:

SCONOX reduces VOC emissions at the same time it reduces NO_x and CO. SCONOX reduces VOC emissions by catalytically oxidizing the VOCs to carbon dioxide (CO_2). SCONOX is capable of reducing VOC emissions by 90%. A 90% reduction in VOC emissions represents 33 tpy of VOCs reduced.

The cost effectiveness of SCONOX applied exclusively as a VOC control is $144,177/ton VOC removed per CGT. This cost effectiveness is well above what has been accepted as cost effective emission controls.

SCONOX has the ability to reduce multiple pollutants., A cost effectiveness analysis using the "excess cost" above what is necessary to reduce NOx and CO cam be applied to a VOC reduction BACT cost effectiveness determination. Based on the cost effectiveness procedure noted above, the cost effectiveness of SCONOX applied as a VOC control is $91,814/ton VOC removed per turbine. This cost effectiveness is about 30 times higher than the normal range of cost effectiveness' applied to CGTs for VOC control.

2.2.3.4 Catalytic Oxidation:

Catalytic oxidation reduces VOCs at the same time it reduces CO. An oxidation catalyst reduces VOC emissions by catalytically oxidizing VOCs to CO2 and water. The technology is capable of reducing VOCs up to 90%.

The rate and degree of VOC oxidation occurring across the catalyst can be affected by its operating temperature, which is related to the catalysts location within the HRSG. Higher catalyst temperatures do lead to higher oxidization rates, but at the expense of steam production. VOC reduction by an oxidation catalyst is also affected by the molecular weight of the organic compound. It is generally accepted by manufacturers and regulators that because formaldehyde is a simple and partially oxidized organic compound, it will oxidize at about the same time and to the same degree as CO[1].

There are 2 ways to evaluate the cost effectiveness of an oxidation catalyst for VOC control. One way is to assume that the entire cost of the catalyst system is for VOC control, the other is to consider that the VOC emission reduction is a no extra cost benefit to the inclusion of the catalyst for CO control.

An 80% reduction in VOC emissions would be 29.4 tpy per turbine. Assuming the cost of an oxidation catalyst is solely for VOC control, the BACT cost effectiveness would be $16,987/ton VOC reduced

Assuming that the reduction in VOC is a benefit resulting from the inclusion of the oxidation catalyst for CO reduction, the cost effectiveness would be $0/ton reduced. However, since the revised BACT analysis for CO does not include a requirement to install a catalyst, this co-benefit does not exist.

---

[1] Roy, Sims; Emission Standards Division, Combustion Group, U.S. Environmental Protection Agency Memorandum to Docket A-95-51; *Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines*, December 30, 1999 (http://www.epa.gov/region07/programs/artd/air/nsr/nsrpg.htm)

2.2.3.5 The following table lists the emission controls considered for BACT and provides a quick synopsis of the above material.

TABLE 3
VOC EMISSION CONTROL FOR AVAILABLE CONTROL TECHNOLOGIES FOR EACH CGT AT THE SATSOP COMBUSTION TURBINE PROJECT

Emission Control Mechanism	VOC Emission Concentration (ppm @ 15% O2)	VOC Emission Rate kg/hr (lb/hr)	Control Efficiency (Ratio to VOC Control	Cost Effectiveness ($/ton pollutant controlled)
Dry Low NO_x (DLN) Combustor and Low NO_x duct burner	2.8	2.86 (6.3)	0%	$0
DLN plus low NO_x duct burners with a separate oxidation catalyst for VOC	0.44	0.55 (1.21)	90%	$16,987
DLN plus low NO_x duct burners with SCONOX	0.44	0.55 (1.21)	90%	$91,814

All emissions calculated by General Electric and Duke/Fluor-Daniel, and converted to carbon equivalent.

2.2.3.6 VOC Emission Limits and Monitoring Requirements:

BACT for VOC is the use of natural gas and oxidation catalyst; however, the VOC emission limitation will not include the removal across the catalyst. VOC emissions from each CGT exhaust stack shall not exceed a 24 hour rolling average of 2.86 kg/hr (6.3 lb/hr), expressed as carbon equivalent. This emission limit represents maximum emissions that occur during duct firing.

EPA Reference Method 25A or 25B, South Coast Air Quality Management District Method 25.3[2], or an equivalent method agreed to in advance by EFSEC, shall be used determine initial and continuing compliance with the VOC limitation. The routine indication of compliance will be provided by compliance with the CO limitation.

2.2.4 Total Pollutant Removal BACT Cost Effectiveness for NO_x, CO and VOC

Since the SCONOX process controls a number of pollutants simultaneously, we have evaluated the comparative cost effectiveness of using SCONOX and the equivalent discrete emission control components to treat the same pollutants. The following control technologies were considered in terms of total pollutant reduction:

---

[2] This is a modification to the EPA test methods optimized for quantifying low concentration VOC sources.

2.2.4.1 SCONOX

As discussed in the previous paragraphs, SCONOX has the capability of reducing NO_x, CO, and VOCs simultaneously. The total expected pollutant reduction would be 785 tons per year per turbine. The annualized cost per turbine is expected to be $4,757,834. This results in a BACT cost effectiveness of $6,061 per ton total pollutant removal.

2.2.4.2 SCR plus Oxidation Catalyst

The use of the SCR and oxidization catalysts reduces the same pollutants as the SCONOX system and provides a control efficiency and cost effectiveness comparison. The total expected pollutant reduction from this combination of controls would be 640 tons per year per turbine. The annualized cost per turbine is expected to be $1,727,962. This results in a BACT cost effectiveness is $2,700 per ton total pollutant removal.

2.2.4.3 BACT Determination

In terms of total pollutant removal, BACT is determined to be SCR plus dry low NOx combustors in the turbines and low NOx duct burners. Emission limitations, monitoring, and reporting requirements are listed above for the individual pollutants.

2.2.5 SULFUR DIOXIDE CONTROL

Sulfur dioxide is a federally regulated air pollutant due to its adverse health effects when breathed at high concentrations, its contribution to acid deposition and visibility impairment. In Washington State SO_2 contributes mostly to visibility impairment and to acid rain.

The following control options were considered for SO_2 control for this facility:

2.2.5.1 Natural Gas Fuel:

Natural gas is considered a clean fuel containing only trace amounts of sulfur. Proposed emission rates for SO_2 are based on an annual average of total sulfur content of 0.5 grains/100 scf and a maximum value of 3 grains/100 scf. The natural gas provided in most of Western Washington is unable to reliably meet the definition of "pipeline natural gas" given in 40 CFR 72.2[3]. The natural gas can reliably meet the criteria for "natural gas" found in the same regulation.

2.2.5.2 Wet Exhaust Gas Scrubbing:

Wet scrubbing is commonly used to control SO_2 emissions from combustion sources other than natural gas fired combustion turbines. Exhaust gas is passed through a spray or packed tower scrubber using an alkaline solution of water and crushed limestone, calcium hydroxide, or sodium hydroxide. The limestone, calcium hydroxide, or sodium hydroxide reacts with the SO_2 generating calcium or sodium sulfites and sulfates. The resulting exhaust stream is passes through a mist eliminator and may require reheating to make the exhaust gas buoyant enough to leave the stack. Wet scrubbers have not been used as controls for natural gas combustion turbines because the concentration of sulfur oxides in the flue gas (in this case 0.27 ppm @ 15% O_2) is too low for known emission controls to effectively reduce SO_2 emissions. The overall technical feasibility this technology to reduce emissions of SO_2 in such a dilute exhaust gas causes this control technology to be considered technically infeasible.

---

[3] Most recently modified on Wednesday, June 12, 2002.

2.2.5.3 Dry Exhaust Gas Scrubbing:

Like wet scrubbing, dry scrubbing uses an alkaline reagent to react with SO_2 and SO_3 in the flue gas. This control system does not use large amounts of water to introduce the reagent into the flue gas, resulting in a dry product that can be removed as a particulate from the exhaust gas. This technology has been used on concentrated sources of SO_2 such as coal-fired boilers and coke calciners. The technology has not been used to control combustion turbine emissions. Dry scrubbers have a limited temperature and minimum flue gas concentration for effective use in controlling SO_2 emissions. The concentration of SO_2 from natural gas combustion (in this case 0.27 ppm @ 15% O_2) is below the effective concentration level for dry scrubbers. The overall technical feasibility this technology to reduce emissions of SO_2 in such a dilute exhaust gas causes this control technology to be considered technically infeasible.

2.2.5.4 Natural Gas Sulfur Removal:

This is a family of chemical treatment methods that remove organic sulfur compounds and hydrogen sulfide from the natural gas. Removal of sulfur compounds from natural gas occurs near the well fields where the gas comes from. Removal of sulfur compounds from the natural gas is necessary to prevent corrosion of the steel gas transport lines and to meet various legal requirements for the quantity of sulfur compounds in natural gas. While it appears to be technically feasible for a single user to remove sulfur from the natural gas used at its own facility, the cost effectiveness of this option has not been considered before. The capital cost for a natural gas sulfur removal facility adequately sized to reduce the natural gas sulfur content of the gas used by the Satsop CT from approximately 0.5 grains/100 scf to 0.2 grains/100 scf has been roughly estimated at $10,000,000 and would reduce the potential SO_2 emissions by about 35 tons per year.

2.2.5.5 BACT Determination

BACT for the Satsop CT Project is the use of natural gas as received from the Northwest pipeline.

2.2.5.6 Emission Limit, Monitoring and Reporting Requirements

The permitted maximum sulfur dioxide emissions using natural gas is calculated to be 0.27 ppm, annual average, at 15% oxygen, and a 1.6 ppm, 1 hour average at 15% O_2, based on an annual average concentration of 0.5 grains total sulfur/100 scf and a short term seasonal concentration of 3.0 g/100 scf in the natural gas. Sulfur dioxide emissions from each CGT exhaust stack shall not exceed 1.5 kg/hr (3.3 lb/hr), annual average and 9.0 kg/hr (19.5 lb/hr), 1 hour average.

Emission monitoring for SO_2 will be achieved by the following means: 1) fuel flow monitoring and total fuel sulfur content reporting that meets the requirements in 40 CFR 72 and 75, Appendix D, and 2) conducting source testing for sulfur dioxide once per calendar quarter using EPA Reference Method 8 for the first year of operation at each CGT exhaust stack. Option 1 can be achieved by use of a continuous gas chromatograph system capable of monitoring the total sulfur content of the gas. This instrument does not need to be owned and operated by Duke Energy, but does need to meet the quality assurance and quality control criteria in the federal requirements referenced above.

If source test results demonstrate compliance with permitted emission limits, subsequent stack testing for sulfur dioxide can be reduced to once every 3 years.

2.2.6 SULFUR TRIOXIDE AND SULFURIC ACID (SULFURIC ACID MIST)

Sulfur trioxide/sulfuric acid is produced in small amounts during the initial combustion of sulfur containing fuels. Additional sulfur trioxide/sulfuric acid is produced as the SO_2 in the flue gas flows across the SCR and oxidation catalysts. It is estimated that 30% of the original SO_2 leaves the PGU stack in the form of sulfur trioxide, ammonium sulfate, ammonium bisulfate, or sulfuric acid. The . sulfur trioxide is quickly converted to sulfuric acid and ammonium sulfate in the ambient atmosphere.

The emission control options evaluated for SO_2 above are equally applicable to the control of SO_3 and H_2SO_4 from the turbines.

2.2.6.1 BACT Determination

The Satsop CT Project has proposed, and EFSEC agrees, that using natural gas constitutes BACT for sulfur trioxide and sulfuric acid control.

2.2.6.2 Emissions Limitation, Monitoring and Reporting Requirements

The emissions of sulfuric acid mist emissions from each CGT stack shall not exceed 0.77 kg/hr (1.7 lb/hr) or 18.51 kg/day (40.8 lb/day).

Quarterly testing of each CGT exhaust stack for sulfuric acid mist utilizing EPA Reference Method 8 is required for the first year of operation. Sulfur trioxide converts to sulfuric acid in this emissions test method and ammonium sulfate and bisulfate salts are also collected in the method. The primary purpose of this testing is to confirm for future use the conversion factor for SO_2 to sulfuric acid mist utilized for this project and to establish the turbine specific conversion factor for use in indicating compliance with the sulfuric acid emission limitation.

If test results demonstrate compliance with permit conditions, subsequent stack testing for sulfuric acid mist can be reduced to once every 3 years.

Routine compliance with the sulfuric acid limitation will be indicated by the quantity of natural gas used, the total sulfur content of the gas and a conversion factor derived from the stack testing required above.

2.2.7 PARTICULATE AND PARTICULATE MATTER LESS THAN 10 MICROMETERS

Particulates are small particles of various materials such as metals, soil, or products of incomplete combustion. Particulates are regulated to reduce their adverse health impacts. Particulate Matter (PM) is defined as fine solid or semisolid material smaller than 100 microns in size. PM_{10} is a subset of particulate and is defined as PM smaller than 10 microns in size.

There are no demonstrated emission control measures to reduce the emissions of particulates from natural gas combustion turbines other than the use of natural gas and good combustion practices to maximize overall combustion efficiency.

2.2.7.1 BACT Determination

EFSEC agrees with Duke Energy that good combustion practices and using only natural gas is BACT for PM and PM10 emissions. The proposed BACT emission limits are listed in Table 4.

2.2.7.2 Emission Limits, Monitoring and Reporting Requirements

EFSEC agrees with the Satsop CT Project that good combustion practice and using only natural gas constitute BACT for PM and PM_{10} emissions. For permitting and modeling purposes it was assumed that PM and PM_{10} are equal. Total PM/PM_{10} emissions from each CGT exhaust stack shall not exceed 263.3 kg/24 hr (580.4 lb/24 hr). The proposed particulate emissions for the Satsop CT Project are shown in Table 4.

EPA Reference Method 201A and 202 shall determine initial compliance with the particulate limits. The same methods will be used for annual source testing conducted to demonstrate continued compliance.

Each CGT stack will meet a visual opacity limit of 5% for a six minute average. Compliance with the opacity standard shall be determined by a certified visual opacity reader making daily observations in accordance with EPA Reference Method 9. The permit will allow the option of installing continuous opacity monitors rather than daily testing with EPA Reference Method 9.

TABLE 4
EMISSION LIMITATIONS FOR PARTICULATE EMISSION LIMITS FOR EACH CGT

Pollutant	Emissions kg/hr (lb/hr)	Emissions Kg/24 hr (lb/24 hr)
PM/PM10, Turbine	7.53 (18.0)[4]	--
PM/PM10, Duct burner	2.49 (5.5)	--
PM/PM10, sulfates and bisulfates	0.953 (2.1)	--
PM/PM10, total	10.97 (24.2)	263.3 (580.4)

2.2.8 Turbine Start-up and Shutdown Emissions

This installation is anticipated to operate as a 'peaking plant' rather than a 'baseload' plant. A peaking plant is a facility that starts and stops operation one to several times per day or only operates when the demand for electricity is projected to be higher than the baseload facilities can provide. A baseload plant is planned to operate continuously at a constant operating rate. As a peaking plant, the turbines at the Satsop CT project are anticipated to start operations from a cold state up to 130 times per year. A cold state is when the turbine has not been operating for at least 2 days and the boiler water has been allowed to cool.

A more common occurrence at peaking plants is to startup from a warm or hot condition. It is anticipated that this may occur up to 2 times per day, though the normal operations would have this at one warm or hot startup per turbine per day. Warm startups take much less time than cold startups. Operating data supplied by Duke Energy and collected in other permit reviews indicate that warm startups can be accomplished in as little as 2 hours per turbine.

Based on power sales forecasts and operational experience at other Duke Energy of North America combustion turbine installations, Duke Energy anticipates that one turbine operating plus the steam generator will be a common operational mode. For this installation one turbine operation would provide approximately 330 MW electrical (MWe). They also anticipate that if the second turbine were required to produce power, operation of the first turbine would be reduced to approximately 300 MWe, to reduce system stresses while the second turbine is brought into operation. Duke Energy has found that start-up of the second turbine would take approximately 1.5 hours for a hot start-up to 3 hours for a warm start-up. Duke Energy has experience with this operational and startup mode at other similar facilities utilizing the same model combustion turbine installed at the Satsop CT.

---

[4] Based on guarantee from General Electric.

The auxiliary boiler is used to reduce the total time it takes for the CGTs to go from a cold to a warm startup condition. Duke Energy and GE have worked together and developed a methodology to start up the pair of turbines in each power island to reduce the cold and warm start-up periods to the shortest time possible.

The start-up process begins with the auxiliary boiler heating the water in the HRSGs followed by one turbine being started at a minimal operational level. The purpose of this is to provide additional heat to its HRSG's boiler water. As the HRSG water increases temperature the turbine operates at higher rates and the second turbine in the power island is started. The turbine operating rate is increased until they are operating at full operational load and the HRSG is up to full operating temperature and pressure. When going from a cold turbine steam generator condition this total process takes about 4 hours for each turbine in a power island. Initially, the emission factors in Table 5 will be applied to estimate the emissions during cold start-up events until Duke Energy develops newer factors.

As noted above, when going from a warm or hot start condition the time necessary to attain full power output and to have the emissions controls in full operation is much shorter. EFESC proposes in the permit that there be 2 startup conditions covered. The first condition is for cold starts. The second condition is to cover warm or hot starts. The warm or hot start condition is defined to end when the emission controls are in full operation or 3 hours has elapsed since an individual turbine started combusting fuel. As they anticipate single combustion turbine operation to be relatively common, the condition will allow a maximum time of 3 hours for each turbine installed in a single power island before compliance with the short-term (less than a 24 hour averaging time) emission limits for the combustion turbine emissions must be met.

TABLE 5
COLD START-UP EMISSIONS FACTORS

Pollutant	Cold Startup Emission Factor (per pair of turbines in one power island)
Nitrogen oxides	1536 lb/startup
Carbon monoxide	5288 lb/startup
Volatile organic compounds	354 lb/startup

During shut-down of the equipment, emissions stop when fuel stops being burned. The emissions then end abruptly.

2.3 COOLING TOWERS:

Wet cooling towers utilize air passage through the cooling water to cool the water for reuse. This direct contact between the cooling water and the air passing through the tower results in entrainment of some of the liquid water in the air stream. The entrained water is carried out of the tower as "drift" droplets. The drift droplets generally contain the same chemical impurities and additives as the water circulating through the tower. Duke Energy proposes to install drift eliminators capable of reducing the drift to ≤0.001% or the recirculating water flow rate. This drift loss rate is commonly found in current generation forced draft cooling towers such as that installed for this project. For an extra cost, drift eliminators with drift rates as low as 0.0005% are available.

Duke/Fluor-Daniel has provided total solids information on the recirculating cooling water. The reported concentration of total solids in the recirculating water is 857 ppm (by weight). The total solids used for recent dispersion modeling was 937.5 ppm. 300 ppm of total solids is added in the form of water treatment chemicals to control the relatively high silica content of the water used for cooling, there will be sulfuric acid added to the recirculating cooling water to reduce the amount of silica that comes out of solution in the cooling tower. Other chemicals are added to reduce the growth of biofilms in the cooling tower. These total dissolved solids and additives can be converted to airborne emissions. The following formula can be used to calculate the quantity of particulate emitted from the cooling tower.

$$\frac{Q \times C \times 0.00001 \times 60 \times 8.34}{1000000} = D$$

Where:
Q = recirculating water flow rate in gallons per minute = 165028 gallons per minute[2]
C = total dissolved solids concentration in parts per million by weight (ppmw) = 1237.5 ppmw[5]
D = particulate emission rate in lb/hr.
0.00001 = the drift loss rate in gallon lost/gallon of recirculating cooling water

Using of this equation results in an emission rate of 0.463 kg/hr (1.02 lb/hr) or 4061 kg/yr (4.5 ton/yr) of PM/PM_{10} per cooling tower.

Installation and operation of drift eliminators with a drift loss rate of 0.001% of the recirculating flow rate constitutes BACT for the cooling towers.

Initial compliance will be based on submission of a copy of the drift eliminator manufacturer's certification that the drift eliminators are installed in accordance with its installation criteria. Duke Energy is required to submit to EFSEC a methodology they will use to estimate PM/PM_{10} emissions from the cooling towers that takes into account each cooling tower's cooling water recirculation rate, the cooling tower dissolved solids (TDS), the effects of fan operation in each cooling cell and the manufacturer's information on drift losses. The methodology shall be accepted by EFSEC prior to the first operation of a cooling tower.

Routine compliance will use the calculation methodology once each quarter to estimate the PM/PM_{10} emissions from each cooling tower. The estimation shall include testing go the recirculating cooling water flow rate, TDS, conductivity, and silica content at the time the TDS sample is taken. An estimation of the cooling tower PM/PM10 emissions shall be made and submitted as part of the initial compliance testing for each CGT and with each quarterly emissions report. The PM/PM_{10} calculation methodology developed by Duke Energy will be used to calculate the emission estimate.

2.4 AUXILIARY BOILER:

Duke Energy has proposed in the Satsop CT application that BACT for all pollutants emitted by the auxiliary boilers to be a combination of flue gas recirculation, low NO_x burners, good combustion practices, and the use of natural gas. Flue gas recirculation and low NOx burners are commonly determined to be BACT for this size boiler when operating on natural gas fuel.

As part of its BACT determination and in recognition of anticipated actual operations, Duke Energy has proposed to limit the hours of operation of each auxiliary boiler to 2500 hours per year. This will be reflected in the approval.

---

[5] Derived from the application materials submitted in April, 2002 and additional information submitted on May 21, 2002.

2.4.1 BACT Determination and Proposed Limits

The emission controls and annual hours of operation limitation proposed by Duke Energy energy is accepted as BACT for all pollutants emitted by the auxiliary boilers Table 6 gives the emission limitations for these units.

TABLE 6
PROPOSED BACT EMISSION LIMITS FOR EACH AUXILIARY BOILER

Pollutant	Emissions (ppm) at 3% O2	Emissions Kg/hr (lb/hr)	Emissions Kg/yr (ton/yr)*
NOx	30	0.467 (1.03)	1170 (1.29)
CO	50	0.485 (1.07)	1215 (1.34)
SO_2	1	0.032 (0.07)	79.5 (0.0875)
PM/PM10	0.005 grains/dscf	3.175 (7.0)	7955 (8.75)
VOC	40	0.213 (0.469)	533 (0.586)
Opacity	6 minute average of 5%	-	-

*Based on 100% load and 2500 hours per year.

2.4.2 Routine Monitoring and Reporting Requirements

Routine compliance will be indicated through boiler operating records indicating hours of operation and fuel flow, and the application of an emission factor derived from stack testing of the installed boilers and periodic stack tests taken at 5 year intervals after the initial compliance test.

Monitoring information will be reported to EFSEC on a quarterly basis at the same time as the reporting for the CGTs.

2.5 DIESEL FUELED EMERGENCY GENERATORS AND EMERGENCY FIRE PUMPS.

These are diesel fueled reciprocating engines. The emergency generators are rated at 500 kilowatts (671 horsepower) and are proposed to be permitted to operate no more than 500 hours per year. These engines are required to meet the emission requirements for new Tier 2, non-road compression ignition engines of this size class found in 40 CFR 89, Subpart B.

2.5.1 Emission limits for diesel emergency generators

TABLE 7
EMISSION LIMITATIONS FOR DIESEL EMERGENCY GENERATORS

Pollutant	Emissions g/kw-hr	Emissions kg/hr (lb/hr)	Emissions kg/yr (ton/yr)
NOx plus VOC	6.4	2.38 (5.26)	1196 (1.3)
CO	3.5	1.75 (3.86)	875 (0.965)
PM/PM_{10}	0.20	0.10 (0.22)	50 (0.055)
SO_2	--	0.122 (0.269)	60.78 (0.067)
Opacity	6 minute average of 5%	-	-

2.5.2 Emissions for emergency fire water pumps

The emergency fire water pumps are intended to operate only when electrical power is not available to the site to supply water for fire suppression. As such they are intended to operate for 500 hours per year or less. These engines will meet the new, non-road compression ignition engine requirements in 40 CFR 89, Subpart B, applicable to the emergency fire water engine size and for purchase in 2002.

2.5.3 Monitoring and Reporting Requirements for Diesel Engines

Monitoring to indicate compliance with the limits shall be by fuel purchase records indicating fuel quality and sulfur content, annual operating hours, and records indicating the nature and type of maintenance performed. Initial compliance will be by certification by the engine manufacturer that the engines meet the applicable emission criteria in 40 CFR 89.

3 AMBIENT AIR QUALITY ANALYSIS

3.1 REGULATED POLLUTANTS

PSD rules require an ambient air quality impacts assessment (40 CFR Part 52.21) from any facility emitting pollutants in significant quantities. Limiting increases in ambient concentrations to maximum allowable increments prevents significant deterioration of air quality.

The ambient impact analysis indicates that all regulated pollutant emissions are below ambient air quality standards established to protect human health and welfare, and no significant ambient air quality impact will result in the vicinity of the project due to its emissions. Table 8 shows the maximum predicted ambient air concentrations predicted by dispersion modeling and is located in Section 4, Ambient Air Quality Impacts.

3.2 TOXIC AIR POLLUTANTS

EFSEC requires an ambient air quality analysis of toxic air pollutants (TAPs) emissions in accordance with WAC 173-460 "Controls for New Sources of Toxic Air Pollutants". The TAPs are evaluated for both acute (24 hour) and chronic (annual) effects as required by the regulation. The quantities of all TAPs known to be emitted from the turbines and duct burners, and diesel engines were estimated and modeled to determine their maximum ambient concentrations. These maximum ambient concentrations were compared to the respective acceptable source impact levels (ASIL) listed in WAC 173-400-150 and 160. These ASILs are not health effect levels, but conservative thresholds that, if exceeded, indicate the need for further investigation of the effects of the TAP on ambient air quality and human health.

The Satsop CT Project is expected to emit small quantities of organic TAPs as products of incomplete combustion and metallic TAPs that were impurities in the fuel or eroded from the metallic portions of the turbines. As discussed above, EFSEC's permit writer determined that BACT for the criteria pollutants is SCR, oxidation catalyst, good combustion practice, and use of natural gas for the combustion turbines; flue gas recirculation, low NOx burners, good combustion practices, and the use of natural gas for fuel for the auxiliary boilers; and duct burners and low sulfur diesel fuel, meeting EPA's new, non-road engine specifications and limited hours of operation for the reciprocating engines. These controls also constitute BACT for toxic air pollutants. Using these control systems and when operating at maximum design capacity, ambient concentrations of all of the TAPs were predicted to be below their respective ASILs.

3.3 AMMONIA EMISSIONS

Ammonia emissions from the Satsop CT Project deserve special discussion. Ammonia is a TAP defined in WAC 173-460. Unreacted ammonia is released from the SCR process because a slight excess is required to reduce NO_x emissions down to the desired levels. The excess ammonia is called "ammonia slip". Ammonia slip can be used as an indicator of SCR catalyst activity. High slip indicates poor operational control or degraded catalyst activity, resulting in higher NOx emissions. SCR manufacturers guarantee that this slip of unused ammonia will be less than 10.0 ppm and occasionally as low as 5 ppm. Recent operating experience indicates that ammonia slip may be maintained at rates consistently below 5 ppm[6] for a number of years after the initial start of the plant's operation. However, while it is technically feasible, there is no long term experience on installations incorporating continuous ammonia monitors that the ammonia slip required to achieve the 2.5 ppm NOx limit for the Satsop CT can be maintained below 5 ppm. At the proposed ammonia limit of 5 ppm, the maximum modeled ammonia concentration out-side the boundary of the Satsop CT Project is about 3.0 micro grams per cubic meter, approximately 3% of the ammonia ASIL found in 173-460 WAC. EFSEC concludes that 5.0 ppm ammonia emission limits for the Satsop CT Project does not threaten human health.

---

[6] For example: PGE Coyote Springs in Morrow County, Oregon and Hermiston Generating Project, Umatilla County, Oregon operate at less than 4.4 ppm ammonia slip with NO_x below 4 ppm. Also see Selective Catalytic Reduction Control of NO_x Emissions, prepared by the Institute of Clean Air Companies, 1660 L St., Suite 1100, Washington, D.C., page 12 (1997).

The SCONOX process does not use or emit ammonia. As discussed above, SCONOX has not passed the economic test of BACT cost effectiveness for the other pollutants it is capable of controlling. However, because the use of SCONOX would eliminate ammonia emissions, Chapter 173-460 WAC requires that SCONOX be considered as a possibility for BACT for TAPs. By using the calculation procedure outlined earlier in this fact sheet, a SCONOX cost can be developed for use in evaluating the cost effectiveness of SCONOX for ammonia elimination. The use of SCONOX would eliminate 148 ton per year of ammonia per turbine, resulting in a cost effectiveness of $10,740/ton. This is considered to be an unreasonable emissions control cost. Thus BACT for ammonia emissions is SCR with an ammonia emission limit of 5.0 ppm.

4 AMBIENT AIR QUALITY IMPACTS

4.1 DISPERSION MODELING METHODOLOGY

Ambient air quality modeling for this project was performed in accordance with the dispersion modeling plan submitted for the Satsop CT permit application, as modified by additional information supplied by Ecology and Duke Energy's consultant. For the analysis of ambient air quality impacts in the area near the facility (up to 50 km from the project site) the non-guideline models ISC-PRIME and AERMOD were used. The ISC-PRIME model was used for the closest 5 km from the facility and the AERMOD model was used for the 5 to 20 km distances. Meteorological information collected by Energy Northwest on the project site and upper air information from the Quillyute station was used to provide the meteorological inputs to these models.

Air quality impact modeling for areas more than 20 km from the facility and for visibility impact analyses used the CALMET/CALPUFF modeling system. Meteorological information was derived from 4 km gridded data produced by the MM5 meso-scale meteorological modeling system. Procedures used to run the CALPUFF model were as recommended by the Federal Land Managers[7].

Dispersion modeling was done for all criteria and toxic air pollutants emitted by the project.

4.2 STATE AND NATIONAL AMBIENT AIR QUALITY STANDARDS

The EPA and the Ecology have established ambient air quality standards. Primary ambient air quality standard concentrations are designed to protect human health and safety, while secondary ambient air quality standard concentrations are designed to protect aesthetic values or chronic health impacts. Dispersion modeling of the projected emissions from the Satsop CT Project indicates that the project will not cause an exceedance of any ambient air quality standard beyond the property line of the facility.

The dispersion modeling performed indicates that the maximum impacts occur within the Capital forest, southwest of Olympia and east of the plant site.

4.3 CLASS I AND CLASS II AREA IMPACTS

The PSD regulations require an evaluation of the effects of the anticipated emissions on visibility and on the degradation of ambient air quality in the areas around the project and within federal Class 1 areas near the facility. Within federal Class 1 areas, the applicant and state are required to evaluate the impact of the project's emissions on ambient air concentrations, pollutant deposition and the impact of the facility's emissions on visibility looking out of and into any class I area. Within Class II areas, the applicant and the state are required to evaluate the impacts of the projects emissions on the same factors, but with a higher acceptability threshold.

Impacts were evaluated in detail for the five established federal Class I areas within 160 kilometer (100 miles) of the project site were evaluated along with 2 Class II areas for which the U.S. Forest Service has asked that this level of evaluation be performed. The federal Class I areas evaluated were Olympic National Park, Mt. Rainier National Park, Goat Rocks Wilderness, Alpine lakes Wilderness, Glacier Peak Wilderness, Mt Hood Wilderness, and Pasayten Wilderness. The impacts to the Class II Mt Baker Wilderness and the Columbia River Gorge National Scenic Area were also evaluated as if the areas were federal Class I areas.

---

[7] Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report, December 2000.

Potential impacts are estimated by modeling the predicted increase in ambient concentrations of some of the pollutants (NOx, CO, and SOx) emitted by the new source, and comparing the predicted concentrations to the appropriate Class I or II increment. EPA has established no significant ambient impact concentration for ozone.

An ozone impact analysis was not performed for this project. The emission of VOC is less than 100 tpy, which is the threshold in the PSD regulations requiring an evaluation of the impact of the impact of the facilities emissions on ambient ozone concentrations.

4.3.1 INCREMENT CONSUMPTION

The effect of emissions from the proposed facility on Class I and Class II area increment consumption were assessed by comparing the maximum predicted pollutant concentrations within the Class I and II areas to the Class I and Class II increments. All predictions are based on a worst-case emission scenario assuming the Satsop CT Project sources are operating at 100 percent load. All maximum predictions are lower than the EPA, National Park Service, U.S. Forest Service and U.S. Fish and Wildlife criteria for requiring cumulative increment consumption analyses. Table 8 shows air quality modeling results compared to the maximum available Class I and Class II PSD increments

TABLE 8
PREDICTED MAXIMUM AIR QUALITY IMPACTS AND ALLOWABLE PSD INCREMENTS

POLLUTANT	Maximum Ambient Class II Area Impact Concentration (μg/m^3)	Class II area allowable increment (μg/m^3)	Maximum Ambient Class I Area Impact Concentration (μg/m^3)	Class I area allowable increment (μg/m^3)
Particulate (PM10)				
Annual	0.91	17	0.00952	4
24-Hour	4.86	30	0.2331	8
Nitrogen Dioxide				
Annual	0.898	25	0.00782	2.5
Sulfur Dioxide				
Annual	0.29	20	0.00102	2
24-Hour	3.5	91	0.0318	5
3-Hour	13.54	512	0.2563	25
1-Hour	40.43	-	-	-

Based on the modeling information, the location of the maximum Class II impacts are east and southeast of the facility. The maximum impacts over 1 hour average duration are approximately 1 km east of the plant site (approximately the BPA substation). The maximum 1 hour average SO_2 concentrations are located in the vicinity of Minot Peak, 5 km southeast of the facility. The location of the maximum Class I area impacts are the ridges above the Staircase area of Olympic National Park.

4.3.2 VISIBILITY

Duke Energy is required to evaluate potential visibility impairment to federal Class I areas located within a radius of 160 km (100 miles) from the Satsop site. Federal Class I areas include National Parks and Wilderness Areas, which are areas where air quality is afforded a higher degree of protection than other areas. Four Class I areas fall within a 100 miles radius of the proposed site: Olympic National Park, Mt. Rainier National Park, Goat Rocks Wilderness Area, and Alpine Lakes

Wilderness Area, all of which are in the State of Washington. Following Ecology's guidance on visibility and other "regional" modeling analyses, the radius of the area modeled for this project also includes Pasayten Wilderness, Glacier Peak Wilderness, Mt. Hood Wilderness, Mt. Baker Wilderness, and the Columbia River Gorge National Scenic Area.

The FLAG report indicates the Federal Land Managers acceptable impact thresholds for visibility impacts caused by a single source. The Federal Land Managers have indicated[8] that they would object to issuance of a PSD approval when the predicted reduction in visibility due to a single source is greater than a 10%. They have also indicated that if the predicted impact on visibility from the proposed source is greater than 5% they would request that a cumulative visibility impact assessment be performed.

The following visibility impact modeling results were based on using a natural gas sulfur content of 0.5 grains/100 scf for the whole year and a NOx emission concentration of 2.5 ppm, 1 hour average. The use of a single annual average natural gas sulfur content does not reflect the annual variability in natural gas sulfur content received in Western Washington or that routine natural gas sulfur monitoring results received by Ecology and others indicate that the sulfur content of the natural gas to be delivered to the Satsop CT site is normally in the 0.2 to 0.4 grain/100 scf range. Based on historical records, natural gas sulfur content can be as high as 3 grains /100 scf for a few days during the period from mid May through July. The days when this occurs are unpredictable and in any given year, the sulfur content may not reach this level. The visibility modeling approach resulted in the following predictions of the visibility impacts to the federal Class 1 areas. Table 9 indicates the federal Class I areas with days having a predicted impact greater than 4%.

TABLE 9
FEDERAL CLASS I AREAS WITH DAYS HAVING VISIBILITY IMPACTS ABOVE 4%, 4 COMBUSTION TURBINES OPERATING[9]

Class 1 Area	Date of Impact	Change in light extinction (visibility)	Approximate location of maximum impact
Olympic National Park	10/28/98	9.07%	Staircase area and area adjacent to Colonel Bob Wilderness
	10/30/98	6.36%	Staircase area and area adjacent to Colonel Bob Wilderness
	2/12/99	5.47%	Southern edge of park
Mt. Rainier National Park	9/24/98	7.44%	Southwest corner of park
Alpine Lakes Wilderness	5/8/98	4.98%	Goat Mountain area

The modeled days of maximum visibility impact above 5% coincide with seasons of the year with considerable cloudiness and rain fall. The area of ONP that is impacted during the above days experiences low visitor usage during this time of the year.

The Bonneville Power Administration has also done regional visibility modeling as part of its National Environmental Policy Act requirements. This modeling indicates that the emissions from this facility do not adversely impact visibility within Western Washington and Northwestern

---

[8] Flag report Page 32

[9] Operation of two turbines was modeled for the original PSD application for NOC/PSD No. EFSEC/2001-01. That information is not repeated here, simply the higher level impacts from the proposed operation of four turbines.

Oregon.

In order to mitigate the predicted visibility impairment indicated above, the applicant requested to perform dispersion modeling using an emission rate based on a 2.0 ppm 24 hour average concentration of NOx. While this modeling analysis is not included above, it confirmed that this reduced level of emissions would eliminate almost all days projected to impact ONP above the 5 % level.

4.3.3 DEPOSITION

Ozone, nitrogen oxides, nitrates and sulfur dioxide fallout have the potential to impact flora and fauna in the area surrounding an emissions source. The impacts of the pollutants from the Satsop CT project on soils, animals, surface water, and vegetation were evaluated. None of the listed pollutants will cause an exceedence of the U.S. Forest Service, Region 6, guidance defining potential adverse impacts within Class II areas.

In conjunction with the work to develop the FLAG report, the National Park Service and the U.S. Fish and Wildlife Service have developed guidance on what levels of nitrate and sulfate deposition increases due to a single source would cause them to perform more detailed reviews of the impacts of the deposition within their Class 1 areas. The threshold established by these agencies is 0.005 kilograms/hectare/year. The maximum predicted nitrogen and sulfur compound deposition from the Satsop CT is within Olympic National Park. The predicted nitrogen deposition level is 0.0062 kg nitrate/hectare/year. The predicted maximum sulfate deposition level is 0.0047 kg sulfate/hectare/year.

The nitrate deposition level exceeds the 0.005 kilogram/hectare/year threshold for National Park Service concern. The National Park Service Air Quality staff[10] have looked a several research reports on resource sensitivity at Olympic NP and have also determined the annual total deposition at the Park[11] to be 2.90 kg/ha/yr for total annual nitrogen deposition and 5.30 kg/ha/yr for total annual sulfur deposition. Based on the information they received about the emissions from the proposed Satsop CT facility and the information they gathered from their literature search and the annual deposition, they do not anticipate that the deposition from this facility will cause a significant impact on resources at the Park.

EFSEC concludes that the Satsop CT Project is unlikely to have a significant impact on vegetation, soil, and aquatic resources in surrounding Class I or Class II areas.

---

[10] E-mail message form Dee Morse, NPS to Alan Newman Ecology dated July 10, 2002.

[11] Based on National Acid Deposition Program data for 1990-2000 and doubling the value listed to include an estimate of dry deposition.

5 OTHER AIR QUALITY IMPACTS

5.1 ACID RAIN PROVISIONS

Title IV of the Clean Air Act Amendments of 1990 requires all facilities with gas turbines rated with an electric output greater than 25 MW which provides at least one third of the output to a distribution system must comply with the 40 CFR Part 75 regulations. The Satsop CT Project will be required to monitor NO_x, SO_2. O_2, and exhaust gas flow rate. The continuous emission monitors required under the NSPS regulations are similar to those required by 40 CFR Part 75; however, the accuracy limits during the annual relative accuracy test audits are more stringent.

5.2 SECONDARY AND CONSTRUCTION EMISSIONS

During the construction phase of the project, workers may be brought into the area to construct the facility, requiring temporary housing and producing motor vehicle emissions during their daily commute to the work site, and from the operation of heavy and other internal combustion engine powered equipment at the project site. During construction, there is the possibility of generation of wind blown dust from earth moving operations and vehicle and equipment operation of unpaved areas of the project site or access roads. Control of this dust can be accomplished through a number of control measures that can be contained in a dust control plan developed by Duke Energy or its construction contractor to be followed by the construction contractor.

During long term operation of the facility there will be daily commuting traffic by the employees of the facility, deliveries of aqueous ammonia for the SCR control systems and periodic deliveries of diesel fuel and other chemicals used at the plant. It is expected that the majority of employees to operate the plant will come from the local area.

6 AIR POLLUTION CONTROL REGULATORY REQUIREMENTS

6.1 This project is subject to the following federal regulations:

Prevention of Significant Deterioration	40 CFR 52.21
New Source Performance Standards	40 CFR 60, Subpart GG
New Source Performance Standards	40 CFR 60, Subpart Da
New Source Performance Standards	40 CFR 60, Subpart Dc
New Source Performance Standards, Quality Assurance Procedures	40 CFR 60, Appendix F
New Source Performance Standards, Performance Specifications	40 CFR 60, Appendix B
National Emission Standards for Hazardous Air Pollutants	40 CFR 63, Subpart YYYY
Acid Rain Permitting	40 CFR 72
Emissions Monitoring and Permitting	40 CFR 75
NO_x Requirements	40 CFR 76
Monitoring of sulfur content of natural gas	40 CFR 60.334(b)(2), 40 CFR 72.2, and 40 CFR Part 75, Appendix D
Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines	40 CFR Part 89

6.2 The source is subject to the following state regulations

General and Operating Permit Regulations for Air Polluting Sources	463-39 WAC
General Regulations for Air Pollution Sources (by reference)	173-400 WAC
Operating Permit Regulation (by reference)	173-401 WAC
Acid Rain Regulation (by reference)	173-406 WAC
Controls For New Sources of Toxic Air Pollutants (by reference)	173-460 WAC

6.2 Conclusion

This project will have no significant impact on ambient air quality. EFSEC finds that Duke Energy has satisfied the requirements for a Notice of construction and PSD approval to amend the Satsop CT Project approval.

For additional information, please contact:

Irina Makarow
Siting Manger
EFSEC
P.O. Box 43172
Olympia, WA 98504-3172
(360) 956-2047
irinam@ep.cted.wa.gov